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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)

REPLY COMMENTS OF NRG ENERGY, INC.

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NRG Energy, Inc. ("NRG") hereby submits the following reply comments to initial responses submitted by a number of parties in the proceeding opened by the California Public Utilities Commission's ("CPUC" or "Commission") *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resource Plans Pursuant to Public Utilities Code Section 769* ("OIR").[1] In this Reply, NRG emphasizes:

- Locational grid benefits are a critical piece of the Distributed Resource Plan ("DRP") value proposition.
- Distributed Energy Resources ("DER") value is multi-layered, extending from the individual customer through the distribution grid and transmission grid to the bulk power delivery system as a whole.
- NRG endorses the remarks of Commissioner Picker at the September 17 workshop – innovation will drive the DER-focused transformation of the current electric system.

As Commissioner Picker stated at the workshop, the Commission's responsibility in this proceeding is to create a "frictionless" network that allows "plug and play" for the growing

[1] The parties to this proceeding to which NRG responds to include: the Alliance for Retail Energy Markets ("AReM"); the California Energy Storage Alliance ("CESA"); the California Independent System Operator Corporation ("CAISO"); the Clean Coalition; EnerNOC, Inc., Johnson Controls, Inc. and Comverge, Inc. (collectively, the "Joint Demand Response Parties"); the Green Power Institute ("GPI"); Marin Clean Energy ("MCE"); the Natural Resources Defense Council ("NRDC"), the Office of Ratepayer Advocates ("ORA"); the Pacific Gas & Electric Company ("PG&E"); the San Diego Gas & Electric Company ("SDG&E"); Southern California Edison Company ("SCE"); and Solar City.

offering of DER products. To achieve that goal, this rulemaking should facilitate the development of plans that provide DER providers with easy access to the network and support their seamless aggregation by third parties, who will augment the value they provide directly to customers with the additional value they provide to the distribution system and the wholesale market.

1. REPLY COMMENTS ON THE SCOPE AND TIMING OF THE RULEMAKING

Responding parties widely differ as to what plan elements and factors need to be included and considered as part of the DRPs in order to truly incentivize DER deployment. NRG submits that the Commission must focus this proceeding on its primary objective: creating the platform for the build-out of the distribution grid.

Some parties' comments focus on more practical possibilities for at least the early stages of this rulemaking. For example, the CAISO suggests that, in the near term, the DRPs should focus on identifying locations that can accommodate significant DER development without major upgrades to distribution infrastructure.[2] EDF offers that the Investor-Owned Utilities ("IOUs") are unlikely to have sufficient time to develop fully formed plans for optimal DER locations by the time the DRPs are due in July 2015.[3]

Conversely, the Joint Demand Response Parties, in their opening comments, cite various public comments from Administrative Law Judge Sullivan, Commissioners Florio, Picker, Peterman and Sandoval, and President Peevey that touch on the far-reaching and transformative possibilities in this current rulemaking.[4] Looking beyond the engineering and operational aspects of distribution systems, some parties assert the need for greater customer choice and

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[2] CAISO at 9.
[3] EDF at 2.
[4] Joint Demand Response Parties at 2-4.

engagement in how DERs are developed and the future distribution system is planned, built, and operated.[5]

Clearly, the question of scope is paramount. It is important to identify the potential DER synergies or constraints in the current distribution network, synthesize metrics that guide developers to the optimal locations, and create compensation mechanisms that turn ideas into resources. This technical work cannot be deferred and must go forward.

At the same time, the utilities' DRPs must be aligned with the Commission's interest in developing policies for the deployment of DER products by innovative businesses and all levels of customer, the nature and extent to which such DER can also provide distribution or wholesale grid support, as well as rate design to support DER deployment.

2. REPLY COMMENTS TO OIR QUESTIONS

1) *What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?*

Parties offered a host of criteria in response to this question, ranging from safety and reliability, to how DRPs will advance California's policy goals, and to cost allocation and recovery. NRG strongly agrees with the three guiding criteria MCE identified in its initial comments: transparency, competitive neutrality, and ease of access to data, billing and interconnection.[6] Both AReM and Vote Solar added a fourth critical criterion, which NRG also supports: how the DRPs will facilitate customer choice and flexibility in deployment.[7]

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[5] Joint Demand Response Parties at 12.
[6] MCE at 7.
[7] AReM at 2-3; Vote Solar at 1-2.

Some parties offered in initial comments that the utility should be able to control any DER that is being compensated for providing reliability services.[8] Assuming the utility is the Distribution System Operator ("DSO"), NRG agrees that the DSO must be able to coordinate the provision of certain reliability services. However, depending on the nature of the reliability service being provided, it is not necessary that DERs be centrally controlled. Instead, a utility contractual or tariff arrangement with a DER provider should allow the DER provider to provide, in aggregate, required reliability services selected from among its portfolio of DER customers and facilities. Such arrangements both allow the DSO to count on DERs being available, while also allowing for more innovation and competitive offerings for DER, greater customer value, and potentially more reliability services at a lower cost, as compared to requiring each customer to accept direct utility control over the energy use or production in their business, home or facility.[9]

Further, NRG notes that some DER reliability services – such as frequency response or flexibility/ramping capability – are provided not just for the support of the distribution network, but for the transmission system as well. As a necessary foundation for unlocking the substantial benefits for customers, NRG emphasizes that this proceeding must ensure that DER resources can be interconnected, operated, and aggregated in the most streamlined and efficient ways possible. To that end, DER connectivity should be standardized, and third party aggregators must have the full opportunity and ability to deliver, consistent with their customers' energy service needs and preferences, the wholesale and transmission support services that DERs provide. NRG notes that there is a public interest benefit in having these types of system-

[8] *See, e.g.,* SDG&E at 5.
[9] NRG also notes that other DSO models, such as an independent DSO, may be possible.

supporting reliability services provided by third-party aggregated DERs that, as managed by the aggregator, will be responsive to the needs of the CAISO.

2) *What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?*

NRG has no comment in reply.

3) *What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?*

As many parties noted, determining the "optimal" location for a particular DER investment should include criteria such as avoided upgrades, the cost of interconnecting at a particular location, and how DER affects the operations of the distribution system to which it is connected. NRG agrees with these criteria, but sees them as incomplete. *First*, NRG agrees with AReM and Solar City that "optimum location" must also be determined by a customer's individual preferences.[10] Many customers seek, for example, to "green" their business operations and are less sensitive to secondary grid implications of their behind-the-meter investments. The Commission's goal should be to enable such customer choices at the lowest cost be requiring each DRP to provide the maximum amount of transparency into grid operations and providing a transparent price signal that will inform customer choices. NRG provides further comments on this below in its reply comments to Question 4. *Second*, NRG agrees with the CAISO that Resource Adequacy deliverability is another key criteria to consider in assessing "optimal location."[11]

4) *What specific values should be considered in the development of a locational value of DER calculus? What is [the] optimal means of compensating DERs for this value?*

[10] AReM at 3-4; Solar City at 5-6.
[11] CAISO at 10.

This question sought input on how to develop the *locational* value of DERs. As a result, many responses focused on the value of avoiding distribution and transmission upgrades or avoiding local capacity costs. While these things unquestionably factor into the determination of locational value, it is important to bear in mind that total DER value includes, but goes well beyond, locational value.

Ultimately, DER value accrues at three levels. Generally, if the value of these three factors to a particular customer exceeds the cost of the DER installation to that customer, then the DER investment is likely to be made. In considering optimal compensation methods, there must be transparent compensation to DER owners for the distribution system and wholesale grid value the DER creates, while also creating additional incentives for developers to locate resources at optimal locations.

Factor #1, DERs may provide customer value independent of where that customer is located and what distribution, transmission, or local capacity investments may otherwise be avoided. For example, a customer may install DER to capture savings and other values the utility cannot deliver, *e.g.,* a very high level of service reliability or power quality, or a high degree of resiliency – the ability to maintain service despite an interruption in grid service. This customer-focused value may not be easily quantified except by the customer. In this regard, NRG agrees with the comments of Solar City that any methodology that determines optimal location for DERs should translate into an incentive to deploy DERs in high-value areas, but that the methodology should not function as a means of discouraging customers who may choose to deploy DERs to obtain significant individual benefits in areas that may have lower locational benefits relative to the distribution grid.[12]

[12] Solar City at 5.

Factor #2, as noted in the question, DERs provide a value to the distribution system in providing greater reliability of service, better power quality, or avoiding upgrades; that value may depend greatly on where the DER is located as well as the DER's technical characteristics. NRG notes that CESA offered the concept of a "Distribution Marginal Price" – a location-specific metric of a DER's value that incorporates both long-term values (such as capital addition deferral), as well as short-term values (such as energy and ancillary services prices) – a concept analogous to, but more complex than, the "Distribution Pricing Zone" concept outlined by NRG in its initial comments. Such locational metrics should prove to be useful in encouraging deployment of DERs in the most suitable locations. To encourage robust DER deployment, compensation should also be stable and predictable. To accomplish this, the Commission should require the establishment of clear and transparent values in each utility's DRP.

Factor #3, DERs will also provide value to the high voltage bulk power delivery system. This value may be location-specific (*e.g.*, avoiding the need for local capacity or transmission-level reactive power support) or largely independent of location (*e.g.*, frequency response). In this regard, NRG agrees both with AReM that this rulemaking must deal with how DERs will integrate with CAISO wholesale markets, so that the wholesale market benefits of DERs are appropriately considered,[13] and with the CAISO that the transmission-distribution interface impacts, as well as DER effectiveness and Resource Adequacy deliverability, must be considered.[14] As noted in the response to Question 1 above, a key to accessing the wholesale and transmission system benefits of DERs is to allow for effective third-party aggregation and to standardize DER control and interconnection. Ensuring that DERs have the option to participate

[13] AReM at 4.
[14] CAISO at 3-4.

in the wholesale, as well as the retail market, potentially allows end-use customers to receive an additional revenue stream to offset DER installation costs.

Additionally, as noted by some parties, by designing the distribution grid to allow a higher level of DERs deployment, other state policy goals can be met such as California's Greenhouse Gas ("GHG") reduction goals, policies related to electrification of the transportation sector, and the renewable portfolio standard.[15] Thus, while the first part of Question 4 focuses on the locational benefits of DERs, it is important to bear in mind that DER value transcends mere locational value, and that a key DER value – meeting individual customer needs independent of other locational benefits to the distribution network – is an important benefit that will be difficult to quantify except by the individual customer. This is one of the primary reasons that the ability of customers to deploy a wide variety of DER solutions must be a key element of the DRPs – only in this manner can the maximum total value of DERs be realized.

5) *What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?*

Given that a significant part of the DER value proposition may stem from providing wholesale services to the CAISO, NRG agrees with the CAISO that the DSO must consider how to coordinate its utilization of dispatchable distributed resources with their use by the CAISO.[16] Such coordination should be compatible with third-party aggregation of dispatchable DER for both the CAISO and the distributed system's purposes.

6) *What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?*

NRG has no comment in reply.

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[15] ORA at 6.
[16] CAISO at 11.

7) *What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?*

While NRG agrees with the long list of benefits noted by other commenters, such as voltage control, reserves, and balancing energy, the benefits of DER extend both "down" to meeting customer-specific needs (such as cost savings, improved power quality, and grid resilience) independent of the DER's value to the distribution system (such as freeing up additional transfer capability by serving that customer's demand) and "up" to the transmission and bulk power system (such as regulation, ramping needs and resource adequacy). Customer adoption of DER, driven by these benefits, must be anticipated and supported by the utilities' DRPs, much as the benefits of electrification are anticipated by a utility today in planning for service extensions to new communities. Feeder lines, substations, and capacity enhancements of the future should all anticipate a high level of DER deployment, some of which may reduce the need for utility infrastructure (*e.g.*, a community microgrid); some of which may increase it (*e.g.*, widespread deployment of electric vehicle charging systems), and some of which may make it much more efficient (*e.g.*, widespread battery storage plus solar providing far less power consumption, but a much greater load factor).

8) *What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?*

NRG has no comment in reply.

9) *What types of data and level of data access should be considered as part of the DRP?*

In its initial comments, ORA observed: "[T]he Commission should rely upon its current data access practices and not use this proceeding to establish new processes and practices for parties to obtain protected and proprietary utility and DER customers' data."[17]

Providing for appropriate access to a customer and utility data is critical to achieving California's ambitious goals for DER deployment in a timely and cost-effective way that leverages private capital investment instead of solely relying on ratepayer funds. While the Commission must ensure customer data confidentiality, inadequate access to information should not become a roadblock to facilitating this important transformation.

NRG also concurs with other parties' ideas as to what other information – such as utility system data, planned major project capital additions, DER functionality that would particularly benefit the distribution system, and other information, such as optimal location maps;[18] pre-application report information;[19] and available capacity on existing circuits and substations[20] – is necessary for locating DERs at optimal locations.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

NRG agrees with other commenters that pilot or demonstration projects should be helpful in demonstrating how specific types of DERs can be integrated into distribution planning and operations.[21] These may appropriately be offered by the utilities under well-defined and specific circumstances to test particular hypotheses regarding the ability of the distribution grid to support DERs. However, any pilot program must not foreclose: (1) the ability to immediately deploy DERs where there are immediate opportunities for customers; and (2) third party

[17] ORA at 8.
[18] SCE at 12.
[19] PG&E at 8.
[20] SDG&E at 13.
[21] Clean Coalition at 7-8; SCE at 13.

engagement in aggregation of DERs to create distribution system and wholesale level benefits, products, or services. NRG also reiterates that pilot programs this type should be established through competitive solicitations.[22]

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

NRG supports GPI's position that the Commission should establish a cycle for revising the DRPs, and set up a plan for ongoing monitoring of progress towards the plans during the course of each cycle.[23] This approach is similar to how the IOUs' procurement plans are revised and reviewed on a two-year cycle through the Long-Term Planning Process.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

As noted by several parties, the DRPs must be consistent with the requirements of Section 769,[24] which include: (1) evaluating the locational benefits of DERs; (2) proposing or identifying standard tariffs to deploy DERs to satisfy distribution planning objectives; (3) proposing cost-effective methods of coordinating existing programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of DERs; and (4) identifying additional utility spending necessary to integrate cost-effective DERs into distribution planning to yield net benefits to ratepayers. The DRPs also should be reviewed to assess their compliance with other core principles key to the success of this effort: transparency of data and of process; providing for customer specific products and engagement; facilitating accessible and meaningful compensation structures; cost-effectiveness, including the ability to attract private capital investment.

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[22] NRG at 10.
[23] GPI at 13.
[24] *E.g.,* PG&E at Appendix A, Page 8.

13) Should the DRPs include discussion of how ownership of the distribution [resources] may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable.

The issue of DER ownership feeds directly into the critical conversation of how third-party and customer-owned DERs can provide – and be compensated for – distribution-level, transmission-level, and system-level reliability services as part of the DRPs. While NRG strongly supports the adoption of a competitively-neutral ownership structure, we agree with a variety of stakeholders, including Vote Solar, that ownership policy not be addressed in the 2015 DRPs[25] in order to avoid pre-judging the outcome of this important policy matter. NRG instead urges the Commission to establish policies that support and encourage, third-party and customer ownership of DERs in its ongoing proceedings, including those addressing electric vehicle (R. 13-11-007) and storage (A. 14-02-006, *et seq.*) proceedings, and most recently, the new demand side proceeding (R.14-10-003), so that the benefits of adding DERs can be enhanced by engaging private capital, not just ratepayer dollars. Further, as IREC notes, to accomplish Section 769's broader vision, it will be necessary to re-examine California's ratemaking framework and to ensure that the utilities' cost-recovery mechanisms are aligned with, and do not inhibit, California's policy goals.[26] That work, too, should begin in conjunction with the rate design reform under consideration in the current proceeding addressing the IOUs' residential rate structures and other issues (R. 12-06-013).

14) What specific concerns around safety should be addressed in the DRPs?

NRG has no comment in reply.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to

[25] Vote Solar at 12-13.
[26] IREC at 20-21.

develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

NRG has no comment in reply.

16) *Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:*

- *Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?*
- *Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?*
- *Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?*
- *Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?*
- *Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?*

NRG has no comment in reply.

3. CONCLUSION

As the Commissioners' August 14 comments indicate, this is a landmark rulemaking that will help define what the electric supply system the next generation will inherit will look like. It also has the potential to unlock customer value and facilitate customer choice for innovative energy products and services. NRG appreciates this opportunity to provide reply comment and looks forward to participating further in this important proceeding.

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Respectfully submitted,

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